WATER EXTRACTION FROM COAL-FIRED POWER PLANT FLUE GAS

Quarterly Progress Report

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ABSTRACT

This quarterly report lists activities performed for the subject project. The project is divided into ten tasks. Task 1 evaluated desiccant materials to test in Task 2. The outcome of Task 1 was the selection of three desiccants to test in Task 2. Task 2 consisted of desiccant testing in a small-scale combustion test furnace at the Energy & Environmental Research Center. Task 2 bench-scale testing of the desiccant performance under actual combustion conditions was completed this quarter. Two fuels, a Powder River Basin coal and natural gas, were tested with the three desiccants. All of the desiccants performed as expected regarding their ability to absorb moisture from the flue gas. Precipitates formed in the last samples taken from two of the desiccants tested with the coal flue gas. These precipitates were analyzed and found to consist of sulfates, carbonates, and combustion ash.

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EXECUTIVE SUMMARY

The goals of this project are to develop technology for recovering water from combustion flue gases to reduce the net water requirements of power plants burning fossil fuels and to perform an engineering evaluation to determine how such technology can be integrated into various power-generating systems, including steam turbine and combined-cycle plants. In the past, power plants burning fossil fuels were designed to generate electricity at least cost under circumstances of abundant coal and natural gas resources and adequate supplies of water for plant cooling. Future plants will need to be designed and operated to conserve both fuel and water. Water is becoming scarce and expensive in many parts of the United States including California, where there is already a strong economic incentive to reduce the net cooling water requirements of power plant subsystems cooling steam turbine condensers and scrubbing stack gases.

Future escalation in the price for natural gas and possible restrictions on carbon emissions from fossil fuels will likewise provide a strong incentive for increasing generating efficiencies. Coal utilization would be most severely impacted by climate change policy initiatives since a coal-fired steam plant emits nearly three times more CO_2 than a natural gas-fired combined-cycle plant with similar generating capacity. Issues of heat and mass transfer concerning water recovery, plant efficiency, and emissions are all related, so technical options for recovering water will open up new opportunities for improving performance relating to the other two factors.

The project is divided into ten tasks as follows:

- Task 1. Desiccant Selection
- Task 2. Desiccant Laboratory Test Evaluation
- Task 3. Test Plan Development
- Task 4. Test Facility and Equipment Design
- Task 5. Equipment and Materials Procurement
- Task 6. Test Equipment Installation
- Task 7. Testing
- Task 8. Test Data Evaluation
- Task 9. Commercial Power Plant Evaluation
- Task 10. Program Management

In the previous quarter, a kickoff meeting was held at the University of North Dakota (UND) Energy & Environmental Research Center (EERC) on November 6, 2003. Attendees were Ms. Barbara Carney of the Department of Energy (DOE) National Energy Technology Laboratory (NETL) and Dr. Bruce Folkedahl, Dr. Michael Jones, Mr. Greg Weber, and Dr. Everett Sondreal, all of UND EERC. Attendees from Siemens Westinghouse Power Corporation (SWPC) were Mr. Lloyd Dean, Mr. Phil Deen, Mr. Dick Newby, and Mr. Eric Weinstein.

Communication protocols for the project were developed, along with a formalized statement of project responsibilities for each of the tasks listed above.

In this quarter, Task 2 was completed. In Task 1, three desiccants were selected for further analysis in Task 2. Task 2 consisted of desiccant testing in a small-scale combustion test furnace at the EERC. Task 2 bench-scale testing of the desiccant performance under actual combustion conditions was completed this quarter. Two fuels, a Powder River Basin coal and natural gas, were tested with the three desiccants. All of the desiccants performed as expected regarding their ability to absorb moisture from the flue gas. Precipitates formed in the last samples taken from two of the desiccants tested with the coal flue gas. These precipitates were analyzed and found to consist of sulfates, carbonates, and coal combustion ash.

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INTRODUCTION AND BACKGROUND

The goals of this project are to develop technology for recovering water from combustion flue gases to reduce the net water requirements of power plants burning fossil fuels and to perform an engineering evaluation to determine how such technology can be integrated into various power-generating systems, including steam turbine and combined cycle plants. An ancillary objective of the engineering evaluation is to identify opportunities for integrating water recovery in ways that improve efficiency and reduce emissions of acid gases and carbon dioxide. Power plants burning fossil fuels have in the past been designed to generate electricity at least cost under circumstances of abundant coal and natural gas resources and adequate supplies of water for plant cooling. Future plants will increasingly need to be designed and operated to conserve both fuel and water. Water is becoming scarce and expensive in many parts of the United States including California, where there is already a strong economic incentive to reduce the net cooling water requirements of power plant subsystems cooling steam turbine condensers and scrubbing stack gases.

Future escalation in the price for natural gas and possible restrictions on carbon emissions from fossil fuels will likewise provide a strong incentive for increasing generating efficiencies. Coal utilization would be most severely impacted by climate change policy initiatives since a coal-fired steam plant emits nearly three times more CO_2 than a natural gas-fired combined cycle plant with similar generating capacity. Issues of heat and mass transfer concerning water recovery, plant efficiency, and emissions are all related, so technical options for recovering water will open up new opportunities for improving performance relating to the other two factors. The amount of water that can be recovered from flue gas is sufficient to substantially reduce and in some cases eliminate the need for off-plant sources of water. The work in this project will demonstrate proof of concept for a desiccant technology that is based on innovative adaptation of established principles used in absorption refrigeration. This technology can be expected to find an immediate market among plants in water-scarce areas. It can also provide added value in the future through integration with other plant systems. Condensing water from flue gas may provide opportunities for removing SO_2 and NO_x, approaching near-zero emissions of acid gases.

Currently, coal-fired power plants require access to water sources outside the power plant for several aspects of their operation in addition to steam cycle condensation and process cooling needs. In integrated gasification combined cycle systems (IGCC), significant water is used in the coal gasification process and for syngas saturation, which is lost through the power plant stack. In pulverized coal (pc) power plants, water inherent in the coal as well as water associated with flue gas scrubbing is lost through the stack. Currently, the strategy used to reduce water consumption in areas where water restrictions are stringent is to employ an air-cooled condenser as opposed to once-through cooling or a cooling tower. However, even plants with air-cooled condensers to minimize water consumption require a significant amount of water in several cases in order to allow for required steam drum blowdown, power augmentation systems, and gas turbine inlet evaporative cooling or fogging systems. At the present time, there is no practiced method of extracting the usually abundant water found in the power plant stack gas. Some work has been done on using mechanical heat rejection to condense water vapor. Such systems would require massive and expensive heat rejection equipment, would be severely limited by high ambient temperatures, and would result in decreased gas turbine performance as a result of higher back pressure due to closed heat exchangers in the flow path. The process being investigated in this project uses liquid desiccant-based dehumidification technology to efficiently extract water from the power plant flue gas, requires minimal heat rejection equipment, can function across the entire ambient range, and results in only a small increase in exhaust pressure.

The advantage of using a desiccant is to facilitate the recovery of useful amounts of water at flue gas temperatures that can be reasonably achieved during power plant operation. Direct contact cooling with a desiccant solution can be engineered to minimize pressure drop, and any water evaporating into the flue gas from an upstream scrubber would be recovered for reuse. The alternative of indirect cooling in an air/flue gas-condensing heat exchanger without a desiccant, which would be limited to applications involving low ambient temperatures, raises significant engineering and economic problems involved with the size and cost of the heat exchanger, pressure drop, corrosion, fouling, and discharge of nonbuoyant stack gas.

This project is a 2-year program to demonstrate the feasibility and merits of a liquid desiccant-based process that will efficiently and economically remove water vapor from the flue gas of coal-fired power plants (IGCC and pc steam plants) and recycle it for in-plant use or export it for clean water conservation. Reduction of water consumption by power plants is quickly becoming a significant issue when attempting to obtain permits for power plants and when required to meet new, more restrictive water consumption allowances currently being considered by the U.S. Environmental Protection Agency (EPA) under proposed Rule 316b.

EXPERIMENTAL

Task 1 was an investigation of the potential viability of various desiccants to meet performance requirements in this application. The selection of a desiccant for the proposed system hinged on several criteria. These criteria were identified, applicable chemical/ physical/ environmental/cost data were gathered, and the data compared. A weighted ranking system based on a criteria list was developed for use in the evaluation and comparison of the candidate desiccants. Three candidate desiccants were chosen for further testing in a bench- scale system. The final candidate desiccant selection will promote a flue gas dehydration process that complies with environmental regulations and results in optimal performance.

In the current quarter, Task 2 was completed. The objective of this task was to test the candidate desiccants selected in Task 1 using the Energy & Environmental Research Center's (EERC's) conversion and environmental process simulator (CEPS). Based in part on the results of this testing, a final desiccant will be selected. This selected desiccant will then be used in the larger pilot-scale Water Extraction from Turbine Exhaust (WETEX) demonstration using the EERC's slagging furnace system as a flue gas source. A more specific objective of this testing is to evaluate the interaction of the candidate desiccant solutions with actual combustion gas from both coal and natural gas combustion. The CEPS flue gas desulfurization (FGD) system is illustrated in Figure 1. The CEPS is designed to nominally top-fire 4.4lb/hr (2 kg/hr) of

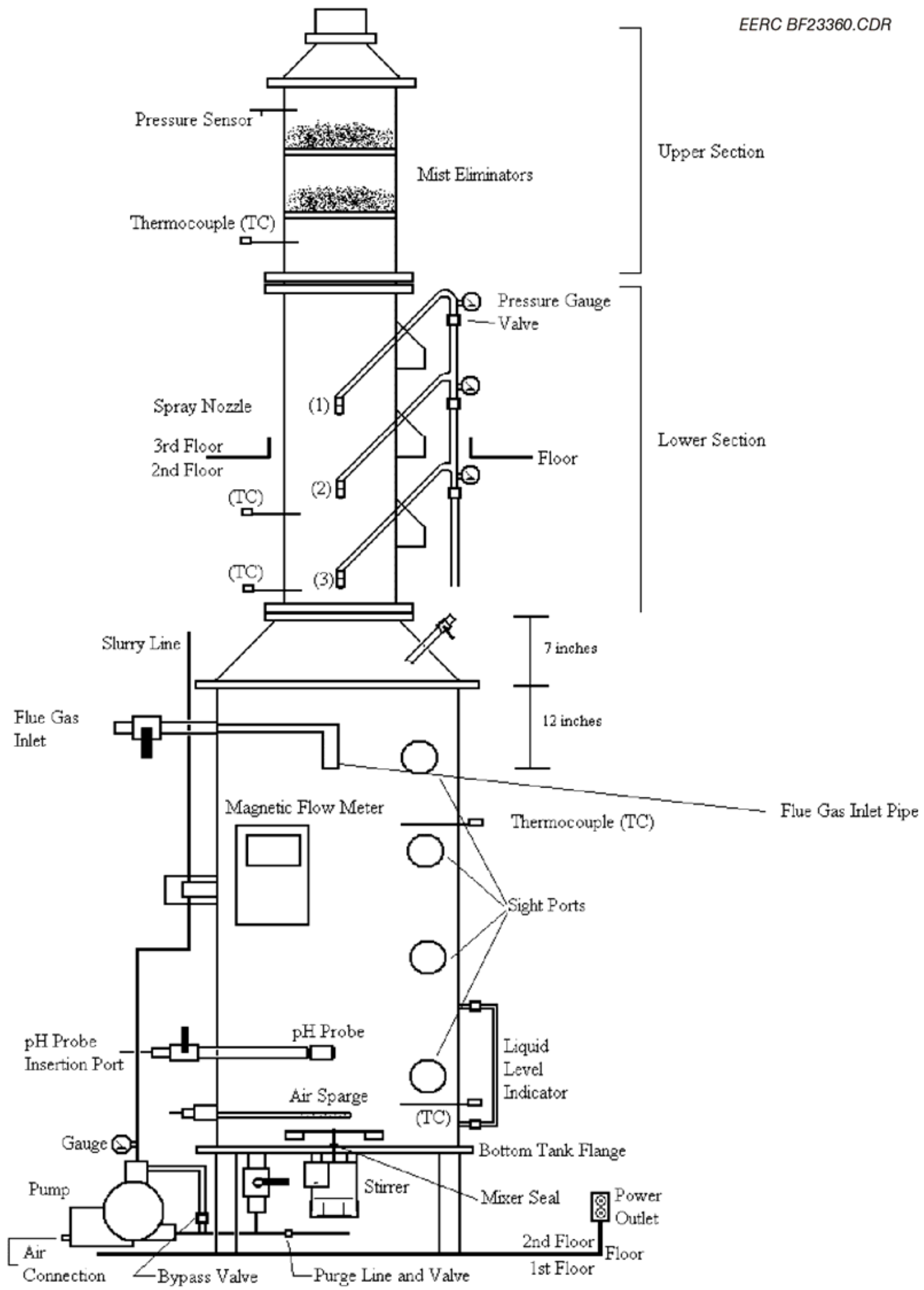

Figure 1. Schematic of the CEPS FGD system.

pulverized coal, with a heat input of 40,000 Btu/hr. Other solid or liquid fuels can be utilized with slight system modifications. It is designed to maintain the flue gas (approximately 8 scfm) generated by the combustion of the fuel at a maximum of 1500°C (2732°F) for the first 4 m (12 ft) of the system, which is referred to as the radiant zone. The first 3 m (9 ft) of the heated radiant zone has an inside diameter (i.d.) of 15.2 cm (6 in.), with the last heated zone reducing down to 7.62 cm (3 in.). The radiant zone exit is through a horizontal, 3.8-cm (1.5-in.)-i.d. ceramic tube. A portion of the particulate is removed before the convective pass section of the CEPS. After the convective section, flue gas flows through an optional ash-fouling test section, a baghouse for final removal of particulate, an air eductor, and up to a stack through the roof.

CEPS is a sealed system maintained under a slight vacuum with an eductor. Electrically heated sections have ceramic tubes exposed to four high-temperature molybdenum silicide heating elements surrounded by high-temperature, fibrous insulating board. Access to the inside of the combustor is available at a number of locations in the radiant zone for sampling, observation, and optical analyses. Access ports penetrate through a combination of cast, abrasion-resistant insulating refractory and high-temperature, fibrous insulating board. The overall CEPS system is housed inside a series of rectangular stainless steel sections bolted together. In juxtaposition to the CEPS, there is a small-scale tank and spray tower which is illustrated in Figure 1. This FGD system is used to simulate sulfur-reduction scrubber systems in coal-fired power plants that can either be isolated from the CEPS when not in use or be a portion of the flue gas path for the combustion gases from the CEPS. This apparatus was used to simulate an absorber spray tower system to evaluate the three desiccants selected in Task 1. The combustion gases were directed into the spray tower where it was contacted by the desiccant stream in a countercurrent flow.

A gas burner was constructed for this series of tests on the EERC CEPS to evaluate the effect of flue gas from the combustion of natural gas on the desiccants. The burner was initially test-fired horizontally outside of the furnace to ensure proper functioning of the burner and attached safety equipment such as the flame sensor and the gas flow shutoff valves. After successful completion of this test, the burner was installed in the CEPS. The gas burner was operated at nominal flow rates of 70 scfh primary air and 24 scfh natural gas to give approximately 32,000 Btu/hr.

Other modifications to the FGD system included the installation of a heat exchanger for maintaining the temperature of the desiccant solution. This was connected to a controller with a thermocouple reading the temperature of the heat exchanger. A valve was installed on the line from the absorber spray pump to the flowmeter. The line continues from the flowmeter to the spray nozzles. The heat exchanger was connected to this valve for inlet fluid, and the outlet was connected to a fitting on the absorber tank to put the heated fluid back into the solution tank. Whenever the pump for the absorber was on, the fluid was passing through this heat exchanger. The valve on the pump line allowed the flowmeter and spray nozzles to be isolated from the pump while the desiccant solution was heating. This reduced the time required to heat the solution at the beginning of tests and allowed for trimming of the temperature during the tests.

The three desiccants chosen in Task 1 were evaluated in Task 2 under identical bench-scale conditions to ascertain which desiccant would be the most appropriate one to take forward to the next phase of pilot-scale testing, and then into full-scale demonstration. All three desiccants chosen have unique beneficial qualities as well as challenges to overcome.

Modeling simulations and calculations were also performed in the previous quarter. The three desiccants selected for testing in the CEPS were used in a simulated potential system and process-flow scheme. Several conditions of operation were used to aid in determining the best possible operational parameters that could be used in the CEPS testing to obtain meaningful results. The three selected desiccants and the operating conditions for testing them are not specifically identified in this report for intellectual property reasons.

RESULTS AND DISCUSSION

In the previous quarter, Task 1 was completed. This task consisted of evaluating multiple desiccants for use in this application. The specific criteria used to evaluate the desiccants were as follows:

- Adverse impact of the flue gas constituents on the desiccant
- Maintenance frequency/complexity cost
- Parts replacement
- Desiccant makeup
- Material handling
- Impact of desiccant on system operation and cost
- Flow characteristics when in solution
- Amount of available property data
- Permeability
- Solubility limits
- Removal of combustion products other than water
- Desiccant capital cost
- Heat transfer properties
- Corrosiveness
- Ability of desiccant to remove water from the exhaust stream
- Environmental effects of desiccant slip

The review of the available information on desiccants in conjunction with the weighting scheme led to the selection of three desiccants to be tested in the EERC CEPS. Two of the desiccants chosen for further evaluation have potential corrosion issues. Additives used in industry to reduce the corrosivity of these desiccants were investigated, but it was determined they would be ineffective in this application. Of the three desiccants chosen, one is an organic desiccant and two are inorganic desiccants.

In this quarter, bench-scale tests were performed to evaluate the performance of the selected desiccants under combustion flue gas conditions. A Powder River Basin (PRB) subbituminous coal was used as the solid fuel with identical tests performed using natural gas fuel to produce flue gas. The test procedure consisted of preheating the CEPS combustion system electrically, filling the storage tank under the absorber tower with a predetermined amount of desiccant, preheating the desiccant in the storage tank, starting the fuel combustion, starting the pump to the spray tower to initiate desiccant flow, and flowing flue gas through the absorber tower countercurrent to the desiccant flow. The duration of the test for each desiccant was 3 hours. At 30-minute intervals, a 500-mL sample of the desiccant was taken. Between tests of different desiccant materials and different fuels, the storage tank under the absorber was emptied and the entire system flushed with water for a minimum of 15 minutes. The system was then dried with a combination of heat tape, hot air dryers, and house air.

The desiccant materials all performed as expected with respect to the amount of moisture removed from the flue gas stream of both the natural gas and coal combustion tests. The lower the vapor pressure of the desiccant the more moisture it removed from the flue gas stream. The flow behavior of all of the desiccants was as expected for the duration of the tests. Although during one of the early tests, the spray nozzles had to be removed and cleaned because of inadequate spray pattern and volume. This partial plugging was attributable to small particulate that was entrained in the solution from the absorber system and was not a reflection of the desiccant flow characteristics. The probable source of the particulate is oxidation of components in the system when sitting idle, producing small particles which then became entrained in the solution.

Sulfur absorption by the desiccants was minimal, with no absorption of sulfur in the natural gas tests and only two of the desiccants absorbing small amounts in the coal combustion tests. The interaction of the flue gas nitrogen with the desiccants also appeared to be minimal, with no nitrate crystalline species detected in precipitate material removed from the solutions.

No precipitates were formed in situ during the testing, however, the duration of these tests were very short, and longer-term testing will be needed to determine if precipitation will need to be addressed. Precipitates did form in samples taken from two of the desiccants from the coal combustion tests after removal from the absorber and cooling of the desiccant material. These precipitates were found in the samples taken near the end of the test for the two desiccants. This precipitate material in the desiccant was analyzed and found to consist of primarily carbonate, sulfate, and some coal combustion ash material. The third desiccant showed no precipitation during or after the testing.

Two of the desiccants contained significant amounts of mercury after the combustion evaluation equal to roughly all of the mercury passing through the system from the coal combustion. It is unusual to capture all of the mercury present in the gas stream unless it is in an oxidized form. In PRB coal combustion, only 10%–30% of the mercury in the coal will become oxidized in the gas stream. It is suspected that there are physical peculiarities inherent in this piece of equipment that enhance oxidation of mercury, allowing it to be sequestered. The source of oxidation of the mercury will not be pursued in this testing phase of the WETEX project.

CONCLUSIONS

Work on this project is proceeding as scheduled. A kickoff meeting was held, and the project communication protocols established between team members. The project is divided into ten tasks. Task 1, completed in the previous quarter, was the review and selection of desiccants for testing in Task 2. Three desiccants were chosen for further evaluation in Task 2, completed in this quarter. This task consisted of physical testing of the desiccants in contact with combustion flue gas in a small-scale combustion system. Two fuels, a PRB coal and natural gas, were used to produce combustion gas in these tests. The three desiccants chosen in Task 1 were tested in the small-scale combustor absorber system. All of the desiccants performed as expected regarding their ability to absorb moisture from the flue gas. The duration of the tests for each desiccant and fuel combination was 3 hours, and no significant interactions between the inorganic flue gas constituents and the desiccants were found during the tests. Precipitates did form for two of the desiccants upon cooling. The precipitates were analyzed and found to consist of carbonates, sulfates, and coal combustion ash material.